

STATEMENT OF BASIS

**ULTRA RESOURCES, INC.
TR16-22A-820
UINTAH COUNTY, UTAH**

EPA PERMIT NO. UT22345-11120

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This STATEMENT OF BASIS gives the derivation of site-specific UIC Permit conditions and reasons for them. Referenced sections and conditions correspond to sections and conditions in the permit.

EPA UIC permits regulate the injection of fluids into underground injection wells so that the injection does not endanger underground sources of drinking water. EPA UIC permit conditions are based upon the authorities set forth in regulatory provisions at 40 CFR Parts 144 and 146, and address potential impacts to underground sources of drinking water. Under 40 CFR 144.35 Issuance of this permit does not convey any property rights of any sort or any exclusive privilege, nor authorize injury to persons or property or invasion of other private rights, or any infringement of other federal, state or local laws or regulations. Under 40 CFR 144 Subpart D, certain conditions apply to all UIC permits and may be incorporated either expressly or by reference. General permit conditions for which the content is mandatory and not subject to site-specific differences (40 CFR Parts 144, 146 and 147) are not discussed in this document.

Upon the Effective Date when issued, the permit authorizes the construction and operation of injection wells so that the injection does not endanger underground sources of drinking water, governed by the conditions specified in the permit. The Permit is issued for the operating life of the injection well or project unless terminated for reasonable cause under 40 CFR 144.39, 144.40 and 144.41. The permit is subject to EPA review at least once every five (5) years to determine if action is required under 40 CFR 144.36(a).

PART I. General Information and Description of Facility

Ultra Resources, Inc.
116 Inverness Drive East, Suite 400
Englewood, Colorado 80112

on

March 3, 2016

submitted an application for an Underground Injection Control (UIC) Program Permit or Permit Modification for the following injection well or wells:

TR16-22A-820
1,902 feet from North Line, 2,383 feet from the West Line, SENW S16, T8S, R20E
Uintah County, Utah

Regulations specific to Uintah-Ouray Indian Reservation injection wells are found at 40 CFR 147 Subpart TT.

The application, including the required information and data necessary to issue or modify a UIC Permit in accordance with 40 CFR Parts 144, 146 and 147, was reviewed and determined by the EPA to be complete.

The permit will expire upon delegation of primary enforcement responsibility (primacy) for applicable portions of the UIC Program to the Ute Indian Tribe or the State of Utah unless the delegated agency has the authority and chooses to adopt and enforce this Permit as a Tribal or State Permit.

TABLE 1.1 shows the status of the well or wells as "New", "Existing" or "Conversion" and for Existing shows the original date of injection operation. Well authorization "by rule" under 40 CFR Part 144 Subpart C expires automatically on the Effective Date of an issued UIC Permit.

TABLE 1.1
WELL STATUS / DATE OF OPERATION

NEW WELLS

Well Name	Well Status	Date of Operation
TR16-22A-820	New	N/A

PART II. Permit Considerations (40 CFR 146.24)

Hydrogeologic Setting

Hydrogeologic Setting

Based upon the Utah Geological Survey Special Study 144 the base of the moderately Saline Groundwater is interpreted to be about 200 feet Below Ground Surface (BGS) in Section 16, T8S, R20E within the Uinta Formation. The base of the Uinta Formation being about 2,444 feet BGS.

Several domestic wells and irrigation wells are located in Sec 9, T8S, R20E about 0.5 miles to the north of the proposed water flood project. The wells are typically shallow <100 feet and apparently tap water bearing zones in the shallow alluvium or shallow Uinta Formation, tributary to the nearby Green River.

Geologic Setting

The main producing interval in the Three Rivers Field is the Eocene-age lower Green River. Oil is trapped stratigraphically in lenticular fluvial deltaic sandstones deposited on the edges of paleo Lake Uinta, as well as in limestones, and “sandy” limestone intervals deposited in a lacustrine environment with fluctuating lake levels. Separating these producing intervals are shales, siltstones, mudstones and marls deposited during relative lacustrine highstands; these provided the organic material for this self-sourcing petroleum system.

Ultra’s proposed waterflood pilot is located on an unfaulted structural monocline that dips Three degrees to the north. The clastic reservoirs in the Lower Green River are fine to very fine grained sandstones and siltstones, 5 to 40 feet in thickness. The carbonate reservoirs generally develop below the Travis Shale, are more continuous than the clastic intervals, and are 10 to 60 feet thick. These alternating pay intervals, and interbedded shales and siltstones, are developed across the waterflood pilot and indicate numerous fluctuations of lake levels and variations of the sediment supply.

Uinta Formation:

The Uinta Formation overlies the Green River formation. The Uinta consists mostly of alluvial plain sediments deposited after Lake Uinta disappeared and the Uinta Basin began to fill with sediments derived from surrounding uplands. Uinta sediments consist mostly of inter-bedded brown mudstones and siltstones with some inter-bedded light tan very fine grained fluvial sandstones. At the location of the Three Rivers water flood area, the Uinta Formation is approximately 2,283 feet thick and is present at the surface just below the Quaternary/Holocene surficial deposits.

Green River Formation:

The Green River Formation is estimated to be found from 2,283 feet to ~ 6,200 feet in the Three Rivers water flood area. The Upper Green River Formation was deposited as a complex sequence of lacustrine and marginal lacustrine sediments consisting of laminated organic-rich carbonate mudstones deposited during high stands of Lake Uinta inter-bedded with basin-margin mudstones, siltstones and fluvial sandstones. During dry-downs of Lake Uinta, soda-rich evaporates were deposited with organic rich basin center mudstones.

Approximately 300 feet of Upper Green River sediments overlie the Birds Nest at the location of Ultra's proposed Three Rivers Water Flood area consists of very dark brown laminated organic-rich mudstones inter-bedded with gray and brown marginal lacustrine siltstones and mudstones. These sediments typically have very low porosity and permeability and are considered to have extremely low vertical permeability in the area of the proposed Three Rivers water flood area.

The Birds Nest aquifer was deposited near the top of the Green River Formation between about 2,455 and 3,173 Below Ground Surface (BGS) as the lake dried up and became a restricted evaporitic basin. Sediments of the Birds Nest are characterized as very fine-grained siltstones and mudstones inter-bedded with dark brown laminated organic-rich carbonate mudstones and evaporate beds (nahcolite) up to two feet thick.

The Upper Green River Formation, in the 300-500 feet below the Birds Nest, consists of similar sediments as described in the 300 feet of Green River sediments immediately overlying the Birds Nest zone. These sediments are dominated by low permeability mudstones and siltstones.

The remainder of the Upper Green River Formation is found between about 3,173 feet and 4,400 feet BGS. The top of Mahogany Bench occurs approximately at 3750 feet bgs. The Mahogany zone is about 1000 feet thick.

The lower Green River Formation (producing zone) is generally between 4,600 feet and 6,200 feet below the surface and is the proposed Enhanced Oil Recovery (EOR) injection zone. The top of the Wasatch Formation is about 6,400 feet BGS.

TABLE 2.1
GEOLOGIC SETTING
TR16-22A-820

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Lithology
Uintah Formation	0	2,520		Sandstone/Shale
Upper Green River	2,520	4,598	63,140	Sandstone and Shale
Lower Green River (Lower Confining Zone)	4,598	6,417	27,000 - 42,000	Limestone, Sandstone and Shale
Wasatch	6,417	6,485		Mudstones, Siltstones, Sandstones

Proposed Injection Zone(s) (TABLE 2.2)

An injection zone is a geological formation, group of formations, or part of a formation that receives fluids through a well. The proposed injection zones are listed in TABLE 2.2.

Injection will occur into an injection zone that is separated from USDWs by a confining zone which is free of known open faults or fractures within the Area of Review.

TABLE 2.2
INJECTION ZONES
TR16-22A-820

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Fracture Gradient (psi/ft)	Porosity	Exempted?*
Lower Green River	4,598	6,391	27,000 - 42,000	0.746		N/A

* **C - Currently Exempted**
E - Previously Exempted
P - Proposed

Confining Zone(s) (TABLE 2.3)

A confining zone is a geological formation, part of a formation, or a group of formations that limits fluid movement above the injection zone. The confining zone or zones are listed in TABLE 2.3.

TABLE 2.3
CONFINING ZONES
TR16-22A-820

Formation Name	Formation Lithology	Top (ft)	Base (ft)
Upper Confining Zone	Shale	4,547	4,598
Lower Confining Zone	Shale	6,391	6,417

Underground Sources of Drinking Water (USDWs) (TABLE 2.4)

Aquifers or the portions thereof which contain less than 10,000 mg/l total dissolved solids (TDS) and are being or could in the future be used as a source of drinking water are considered to be USDWs. The USDWs in the area of this facility are identified in TABLE 2.4.

TABLE 2.4
UNDERGROUND SOURCES OF DRINKING WATER (USDW)
TR16-22A-820

Formation Name	Formation Lithology	Top (ft)	Base (ft)	TDS (mg/l)
Uinta Formation	Mudstone, Siltstones and Sandstones	0	350	Not Analyzed

PART III. Well Construction (40 CFR 146.22)

TABLE 3.1
WELL CONSTRUCTION REQUIREMENTS
TR16-22A-820

Casing Type	Hole Size (in)	Casing Size (in)	Cased Interval (ft)	Cemented Interval (ft)
J-55	8.64	5.50	0 - 6,472	1,260 - 6,472
J-55	12.25	8.63	0 - 1,053	-

The approved well completion plan will be incorporated into the Permit as APPENDIX A and will be binding on the Permittee. Modification of the approved plan is allowed under 40 CFR 144.52(a)(1) provided written approval is obtained from the Director prior to actual modification.

Casing and Cementing (TABLE 3.1)

The well construction plan was evaluated and determined to be in conformance with standard practices and guidelines that ensure well injection does not result in the movement of fluids into USDWs. Well construction details for this "new" injection well is shown in TABLE 3.1.

Remedial cementing may be required if the casing cement is shown to be inadequate by cement bond log or other demonstration of Part II (External) mechanical integrity.

Tubing and Packer

Injection tubing is required to be installed from a packer up to the surface inside the well casing. The packer will be set above the uppermost perforation. The tubing and packer are designed to prevent injection fluid from coming into contact with the outermost casing.

Tubing-Casing Annulus (TCA)

The TCA allows the casing, tubing and packer to be pressure-tested periodically for mechanical integrity, and will allow for detection of leaks. The TCA will be filled with fresh water treated with a corrosion inhibitor or other fluid approved by the Director.

Monitoring Devices

The permittee will be required to install and maintain wellhead equipment that allows for monitoring pressures and providing access for sampling the injected fluid. Required equipment may include but is not limited to: 1) shut-off valves located at the wellhead on the injection tubing and on the TCA; 2) a flow meter that measures the cumulative volume of injected fluid; 3) fittings or pressure gauges attached to the injection tubing and the TCA for monitoring the injection and TCA pressure; and 4) a tap on the injection line, isolated by shut-off valves, for sampling the injected fluid.

All sampling and measurement taken for monitoring must be representative of the monitored activity.

PART IV. Area of Review, Corrective Action Plan (40 CFR 144.55)

TABLE 4.1
AOR AND CORRECTIVE ACTION

Well Name	Type	Status (Abandoned Y/N)	Total Depth (ft)	TOC Depth (ft)	CAP Required (Y/N)
TR16-11T-820	Producer	No	6,597	825	No
TR16-12-820	Producer	No	6,678	1,800	No
TR16-12T-820	Producer	No	6,540	1,750	No
TR16-14T-820	Producer	No	6,530	2,280	No
TR16-21-820	Producer	No	6,880	2,830	No
TR16-21T-820	Producer	No	6,702	1,900	No
TR16-22-820	Producer	No	6,765	2,985	No
TR16-23-820	Producer	No	6,720	1,582	No
TR16-24T-820	Producer	No	6,633	2,050	No
TR16-32-820	Producer	No	6,767	1,660	No
TR16-32T-820	Injector	No	6,600	1,470	No

TABLE 4.1 lists the wells in the Area of Review ("AOR") and shows the well type, operating status, depth, top of casing cement ("TOC") and whether a Corrective Action Plan ("CAP") is required for the well.

Area Of Review

Applicants for Class I, II (other than "existing" wells) or III injection well Permits are required to identify the location of all known wells within the injection well's Area of Review (AOR) which penetrate the injection zone, or in the case of Class II wells operating over the fracture pressure of the formation, all known wells within the area of review that penetrate formations which may be affected by increased pressure. Under 40 CFR 146.6 the AOR may be a fixed radius of not less than one quarter (1/4) mile or a calculated zone of endangering influence. For Area Permits, a fixed width of not less than one quarter (1/4) mile for the circumscribing area may be used.

Corrective Action Plan

For wells in the AOR which are improperly sealed, completed or abandoned, the applicant shall develop a Corrective Action Plan (CAP) consisting of the steps or modifications that are necessary to prevent movement of fluid into USDWs.

The CAP will be incorporated into the Permit as APPENDIX F and become binding on the Permittee.

Corrective action is not currently required for the proposed injection and AOR Wells. Ten production wells and one injection well are within the AOR of the proposed injection well converted from production (TR16-22A-820). Three AOR wells (TR16-11T-820, TR16-32-820 and TR16-21-820) have 80% CBI for 18 feet. The following seven AOR wells and one injector did not achieve 80% CBI for 18 feet (5.5 inch production casing) as typically required for an upper seal in the proposed injector's upper confining zone (CZ). However, considering the bonded cement for these eight wells throughout the CZ, the top of the cement ranging between 2,682 feet to

3,349 feet above the top of the injection zone, and the distance from the injector there is no added risk to the USDWs in the area.
These eight AOR wells are:

- TR16-21T-820
- TR16-22-820
- TR16-12T-820
- TR16-12-820
- TR16-14T-820
- TR16-24T-820
- TR16-32T-820 (injector)
- TR16-23-820

PART V. Well Operation Requirements (40 CFR 146.23)

TABLE 5.1
INJECTION ZONE PRESSURES
TR16-22A-820

Formation Name	Depth Used to Calculate MAIP (ft)	Fracture Gradient (psi/ft)	Initial MAIP (psi)
Lower Green River	4,598	0.746	1,375

Approved Injection Fluid

The approved injection fluid is limited to Class II injection well fluids pursuant to 40 CFR § 144.6(b). For disposal wells injecting water brought to the surface in connection with natural gas storage operations, or conventional oil or natural gas production, the fluid may be commingled and the well used to inject other Class II wastes such as drilling fluids and spent well completion, treatment and stimulation fluid. Injection of non-exempt wastes, including unused fracturing fluids or acids, gas plant cooling tower cleaning wastes, service wastes, and vacuum truck and drum rinsate from trucks and drums transporting or containing non-exempt waste, is prohibited.

Injection Pressure Limitation

Injection pressure, measured at the wellhead, shall not exceed a maximum calculated to assure that the pressure used during injection does not initiate new fractures or propagate existing fractures in the confining zones adjacent to the USDWs.

The applicant submitted injection fluid density and injection zone data which was used to calculate a formation fracture pressure and to determine the maximum allowable injection pressure (MAIP), as measured at the surface, for this permit.

TABLE 5.1 lists the fracture gradient for the injection zone and the approved MAIP, determined according to the following formula:

$$FP = [fg - (0.433 * sg)] * d$$

FP = formation fracture pressure (measured at surface)
fg = fracture gradient (from submitted data or tests)
sg = specific gravity (of injected fluid)
d = depth to top of injection zone (or top perforation)

Injection Volume Limitation

Cumulative injected fluid volume limits are set to assure that injected fluids remain within the boundary of the exempted area. Cumulative injected fluid volume is limited when injection occurs into an aquifer that has been exempted from protection as a USDW.

Mechanical Integrity (40 CFR 146.8)

An injection well has mechanical integrity if:

1. there is no significant leak in the casing, tubing, or packer (Part I); and
2. there is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore (Part II).

The permit prohibits injection into a well which lacks mechanical integrity.

The permit requires that the well demonstrate mechanical integrity prior to injection and periodically thereafter. A demonstration of mechanical integrity includes both internal (Part I) and external (Part II). The methods and frequency for demonstrating Part I and Part II mechanical integrity are dependent upon well-specific conditions as explained below.

PART VI. Monitoring, Recordkeeping and Reporting Requirements

Injection Well Monitoring Program

At least once a year the permittee must analyze a sample of the injected fluid for total dissolved solids (TDS), specific conductivity, pH, and specific gravity. This analysis shall be reported to EPA annually as part of the Annual Report to the Director. Any time a new source of injected fluid is added, a fluid analysis shall be made of the new source.

Instantaneous injection pressure, injection flow rate, cumulative fluid volume and TCA pressures must be observed on a weekly basis. A recording, at least once every thirty (30) days, must be made of the injection pressure, annulus pressure, monthly injection flow rate and cumulative fluid volume. This information is required to be reported annually as part of the Annual Report to the Director.

PART VII. Plugging and Abandonment Requirements (40 CFR 146.10)

Plugging and Abandonment Plan

Prior to abandonment, the well shall be plugged in a manner that isolates the injection zone and prevents movement of fluid into or between USDWs, and in accordance with any applicable federal, state or local law or regulation. Tubing, packer and other downhole apparatus shall be removed. Cement with additives such as accelerators and retarders that control or enhance cement properties may be used for plugs; however, volume-extending additives and gel cements are not approved for plug use. Plug placement shall be verified by tagging. Plugging gel of at least 9.2 lb/gal shall be placed between all plugs. A minimum 50 ft surface plug shall be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface. Within sixty (60) days after plugging the owner or operator shall submit Plugging Record (EPA Form 7520 – 13) to the Director. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. The plugging and abandonment plan is described in Appendix E of the Permit.

PART VIII. Financial Responsibility (40 CFR 144.52)

Demonstration of Financial Responsibility

The Permittee is required to maintain financial responsibility and resources to close, plug and abandon the underground injection operation in a manner prescribed by the Director. The permittee shall show evidence of such financial responsibility to the Director by the submission of a surety bond, or other adequate assurance such as financial statements or other materials acceptable to the Director. The Regional Administrator may, on a periodic basis, require the holder of a lifetime permit to submit a revised estimate of the resources needed to plug and abandon the well to reflect inflation of such costs, and a revised demonstration of financial responsibility, if necessary. Initially, the operator has chosen to demonstrate financial responsibility with:

Bond Rider, received April 19, 2016

Evidence of continuing financial responsibility is required to be submitted to the Director annually.